Appendix D

Reserve Additions

The Reserve Additions algorithm calculates units of oil and gas added to proved and inferred reserves. Reserve additions are calculated through a set of equations accounting for new field discoveries, discoveries in known fields, and incremental increases in volumetric recovery that arise during the development phase. There is a “finding rate” equation for each phase in each region and for each fuel type.

Each newly discovered field adds not only proved reserves but also a much larger amount of inferred reserves. Proved reserves are reserves that can be certified using the original discovery wells; inferred reserves are those hydrocarbons that require additional drilling before they are termed proved. Additional drilling takes the form of other exploratory drilling and development drilling. Within the model, other exploratory drilling accounts for proved reserves added through new pools or extensions, and development drilling accounts for reserves added through revisions.

The volumetric yield from a successful new field wildcat well is divided into proved reserves and inferred reserves. The proportion of reserves allocated to each category is based on historical reserves growth statistics. Specifically, the allocation of reserves between proved and inferred reserves is based on the ratio of the initial reserves estimated for a newly discovered field relative to ultimate recovery from the field.[23]

Functional Forms

Oil or gas reserve additions from new field wildcats are a function of the cumulative new field discoveries, the initial estimate of recoverable resources for the fuel, and the rate of technological change.

Total successful exploratory wells are disaggregated into successful new field wildcats and other exploratory wells based on a historical ratio. In this appendix, successful new field wildcats are designated by the variable $SW1$, other successful exploratory wells by $SW2$, and successful development wells by $SW3$.

The major inputs to the new field reserve addition equation are new reserve discoveries and the resource base. This approach relies on the finding rate equation:

$$FR1_{r,k,t} = FR10_{r,k,t} * \left(1 - \frac{CUM\_U_{r,k,t}}{BIG\_U_{r,k}}\right)^{DELTA\_B_{r,k}}, \quad (1)$$

where

$$FR10_{r,k,t} = INITFR1_{r,k,t} * FRTECH_{r,k,t} * ECON_{r,k,t}, \quad (2)$$

and

$FR1$ = new field wildcats finding rate

$FR10$ = initial finding rate for new field wildcats

CUM_U = cumulative new field discoveries

BIG_U = ultimate recovery resource estimate

$DELTA\_B$ = hyperbolic decline rate

$FR10$ = initial finding rate adjusted for technology and economics

$INITFR1$ = initial finding rate

$FRTECH$ = technology adjustment

$ECON$ = economic adjustment

r = region

k = fuel type (oil or gas)

t = year.

Under the above specification, the yield from new field wildcat drilling in the absence of technological and economic change declines with cumulative discoveries. Technological progress is split into four regimes (2 past, 1 current, and 1 future) and is of the form

$$FRTECH_{r,k,t} = 1 + \frac{\alpha_{r,k}}{1 + e^{\beta 1_{r,k} * (t - \beta 2)}}, \quad (3)$$

where

α = peak impact

$\beta 1$ = rate of change

$\beta 2$ = peak year

r = region

k = fuel type

t = year.

The economic impact is defined by

[23] A more complete discussion of the topic of reserve growth for producing fields can be found in Energy Information Administration, *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy Strategy*, SR / NES / 90-05 (Washington, DC, 1990), Chapter 3.

$$ECON_{r,k,t} = \frac{OFE_{r,k} * \dfrac{CUM\_U_{r,k,t}}{CUM\_NFW_{r,k,t}} + POA_{r,k}}{OFE_{r,k} * \dfrac{CUM\_U_{r,k,t}}{CUM\_NFW_{r,k,t}} + WHP_{r,k,t}}, \quad (4)$$

where

OFE = assumed economic impact coefficient

CUM_U = cumulative new field discoveries

CUM_NFW = cumulative new field wildcats drilled

POA = historical average wellhead price

WHP = wellhead price.

The above equations provide a rate at which undiscovered resources are converted into proved and inferred reserves as a function of cumulative new field discoveries. Given an estimate for the ratio of ultimate recovery from a field to the initial proved reserve estimate, $X_{r,k}$, the $X_{r,k}$ reserve growth factor is used to separate newly discovered resources into proved and inferred reserves. Specifically, the change in proved reserves from new field discoveries for each period is given by integrating the finding rate with respect to wells drilled in each period:

$$\Delta R_{r,k,t} = \frac{1}{X_{r,k}} \int_0^{SW1_{r,k,t}} FR1_{r,k,t}\, d(SW1) \quad (5)$$
$$\frac{1}{X_{r,k}} \int_0^{SW1_{r,k,t}} FR1_{r,k,t-1}(1+\beta 1) * \exp(-\delta 1_{r,k,t} * SW1_{r,k,t})\, d(SW1) \;,$$

where

X = reserves growth factor

ΔR = additions to proved reserves.

The terms in Equation (5) are all constants in period t, except for the $SW1$. X is derived from historical data and it is assumed to be constant during the forecast period. $FR1_{r,k,t-1}$ and $\delta 1_{r,k,t}$ are calculated, prior to period t, based on lagged variables and fixed parameters as shown in Equations (3) and (4).

Reserves are converted from inferred to proved with the drilling of other exploratory wells and developmental wells in a way similar to the way in which proved and inferred reserves are modeled as moving from the resource base, as described above. The volumetric return to other exploratory wells and developmental wells is shown in the following equations:

$$FR2_{r,k,t} = FR2_{r,k,t-1} * (1+\beta 2) * \left(\frac{whp_{r,k,t}}{avgwhp_{r,k}}\right)^{\alpha 2} * e^{-\delta 2_{r,k,t-1} * SW2_{r,k,t}} \;, \quad (6)$$

where

$FR2$ = other exploratory wells finding rate

$\beta 2$ = technology parameter for $FR2$

$\alpha 2$ = economic parameter for $FR2$

whp = wellhead price in year t

$avgwhp$ = historical average wellhead price

$\delta 2$ = decline factor

$SW2$ = successful other exploratory wells;

and

$$FR3_{r,k,t} = FR3_{r,k,t-1} * (1+\beta 3) * \left(\frac{whp_{r,k,t}}{avgwhp_{r,k}}\right)^{\alpha 3} * e^{-\delta 3_{r,k,t-1} * SW3_{r,k,t}} \;, \quad (7)$$

where

$FR3$ = developmental wells finding rate

$\beta 3$ = technology parameter for $FR3$

$\alpha 3$ = economic parameter of $FR3$

$\delta 3$ = *decline factor*

$SW3$ = successful developmental wells.

The decline rates for the exponentially declining functions are shown in the following equations for other exploratory drilling and developmental drilling, respectively:

$$\delta 2_{r,k,t} = (FR2_{r,k,t}) \div [(I_{r,k} * (1+TECH)^{t-T} + CUMRES2_{r,k,t-1} - CUMRES3_{r,k,t-1}] \;, \quad (8)$$

$$\delta 3_{r,k,t} = (FR3_{r,k,t}) \div [(I_{r,k} * (1+TECH)^{t-T} + CUMRES2_{r,k,t-1} - CUMRES3_{r,k,t-1}] \;, \quad (9)$$

where

I = initial inferred reserves estimate

$TECH$ = technological improvement rate applied to inferred reserves

$CUMRES2$ = cumulative inferred reserve additions from new discoveries

$CUMRES3$ = cumulative extensions and revisions.

The conversion of inferred reserves to proved reserves occurs as both other exploratory wells and developmental wells exploit a single stock of inferred reserves. The entire stock of inferred reserves can be exhausted through either the other exploratory wells or developmental wells alone. This extreme result is unlikely, however, given reasonable drilling levels in any one year. Nonetheless, the simultaneous extraction from inferred reserves by both drilling types could be expected to affect the productivity of both. Specifically, the more one drilling type draws down the inferred reserve stock, the more likely it is that there could be a corresponding acceleration in the productivity decline for the other type. In a given year, the same initial recoverable resource value (i.e., the denominator expression in the derivation of δ2 and δ3) is decremented by either type of drilling.

Total reserve additions in period t are given by the following equation:

$$RA_{r,k,t} = \frac{1}{X_{r,k}} \int_0^{SW1_{r,k,t}} FR1_{r,k,t}\, d(SW1) + \int_0^{SW2_{r,k,t}} FR2_{r,k,t}\, d(SW2) + \int_0^{SW3_{r,k,t}} FR3_{r,k,t}\, d(SW3) \quad . \tag{10}$$

Finally, total end-of-year proved reserves for each period equal:

$$R_{r,k,t} = R_{r,k,t-1} - Q_{r,k,t} + RA_{r,k,t} \quad , \tag{11}$$

where

R = reserves measured at the end of the year

Q = production.

Production-to-Reserves Ratio

The production of nonassociated gas in NEMS is modeled at the "interface" of the Natural Gas Transmission and Distribution Module (NGTDM) and the Oil and Gas Supply Module (OGSM). Oil production is determined within the OGSM. In both cases, the determinants of production include the lagged production-to-reserves (P/R) ratio and price. The P/R ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves.

For each year t, the P/R ratio is calculated as:

$$PR_t = \frac{Q_t}{R_{t-1}} \quad , \tag{12}$$

where

PR_t = production-to-reserves ratio for year t

Q_t = production in year t, received from the NGTDM and the Petroleum Marketing Module (PMM)

R_{t-1} = end-of-year reserves for year t-1 or, equivalently, beginning-of-year reserves for year t.

PR_t represents the rate of extraction from all wells drilled up to year t (through year t-1). To calculate the expected rate of extraction in year t+1, the model combines production in year t with the reserve additions and the expected extraction rate from new wells drilled in year t. The calculation is given by:

$$PR_{t+1} = \{[R_{t-1} * PR_t * (1 - PR_t)] + (PRNEW * RA_t)\} \div R_t \quad , \tag{13}$$

where

PR_{t+1} = expected P/R ratio for year t+1

$PRNEW$ = long-term expected P/R ratio for all wells drilled in the forecast

R_t = end-of-year reserves for year t or, equivalently, beginning-of-year reserves for year t+1.

The numerator, representing expected total production for year t+1, is the sum of two components. The first represents production from proved reserves as of the beginning of year t, or the expected production in year t, $R_{t-1} * PR_t$, adjusted by 1 - PR_t to reflect the normal decline from year t to year t+1. The second represents production from reserves discovered in year t. No production from reserves discovered in year t+1 is assumed for year t+1.

Under this option, PR_t is constrained not to vary from PR_{t-1} by more than 5 percent. It is also constrained not to exceed 30 percent.

The values for R_t and PR_{t+1} are passed to the NGTDM and the PMM for use in their market equilibration algorithms which solve for equilibrium production and prices for year t+1 of the forecast using the following short-term supply function:

$$Q_{r,k,t+1} = [R_{r,k,t}] * [PR_{r,k,t} * (1 + \beta_{r,k} * \Delta P_{r,k,t+1})] \quad , \tag{14}$$

where

R_t = end-of-year reserves in period t

PR_t = extraction rate in period t

β = estimated short-run price elasticity of supply

ΔP_{t+1} = proportional change in price from year t to t+1, given by $(P_{t+1} - P_t)/P_t$.

The P/R ratio for period t, PR_t, is assumed to be the approximate extraction rate for period t+1 under normal operating conditions. The product $R_{r,k,t}*PR_t$ is the expected, or normal, operating level of production for year t+1. Actual production in year t+1 will deviate from expected production, depending on the proportionate change in price from period t and on the value of the short-run price elasticity. The OGSM passes estimates of β to the NGTDM and PMM that can be used in solving for the market equilibria.

The P/R ratio is multiplied by beginning-of-year crude oil reserves to estimate production by region. This volume is then passed to the PMM for use in market equilibration.